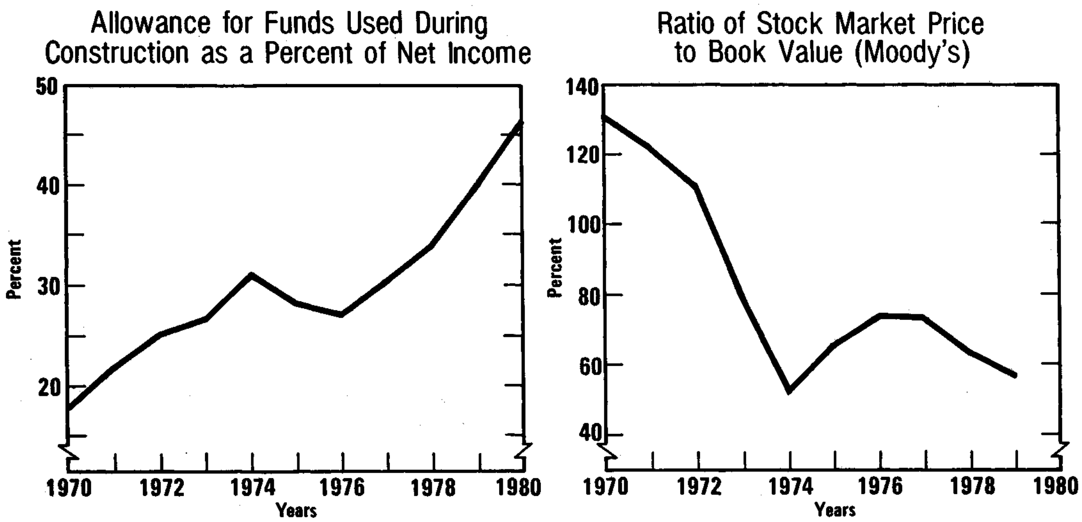
Figure 2.
Financial Trends in Investor Owned Electric Utilities According to Two Measures: 1970-1980



SOURCE: Adapted by CBO from H. L. Culbreath, "An Overview of the Financial Difficulties of the Electric Utility Industry," Statement by Edison Electric Institute before the House Committee on Energy and Commerce, Subcommittee on Energy, Conservation and Power (6 April 1981).

utilities--that is, the majority of utilities. In 1980, AFUDC accounted for 46 percent of reported after-tax income; three years earlier, the comparable figure was 30 percent. 1/

Unlike capital expenditures, escalating fuel costs may be quickly recovered under most PUC regulations. More than half of the nation's PUCs provide an automatic fuel adjustment clause to utilities within their jurisdictions. 2/ Under the fuel adjustment provisions, all or at least a major part of the cost increases of fuels may be reflected immediately in higher rates to consumers, with no need for a hearing or other administrative procedure. These provisions effectively protect utilities against the risks of reduced revenue from higher fuel costs.

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1. See Statement of H.L. Culbreath, for the Edison Electric Institute, "An Overview of the Financial Difficulties of the Utility Industry and the Impact on the Funding of Necessary Future Construction," given April 6, 1981, before the U.S. House of Representatives Committee on Energy and Commerce, Subcommittee on Energy, Conservation, and Power.

2. See National Association of Regulatory Utility Commissioners, "1979 Annual Report on Utility and Carrier Regulation" (October 1980).

The combined effect of detrimental regulatory treatment of capital investments and advantageous fuel adjustment clauses is to discourage replacement of expensive oil- and gas-fired capacity and older coal-burning facilities, typically meeting standards more relaxed than the current NSPS (see Chapter II). The short-term result is that construction of capital-intensive new plants, which are cleaner burning and more efficient, is delayed or postponed indefinitely. These twin outcomes do little to further the federal objectives of establishing a reliable future electricity supply and increasing the use of coal.

CONTRIBUTION OF AIR POLLUTION CONTROL COSTS TO INDUSTRY CAPITAL EXPENSES

In part because of increased demand for electricity, delays in construction, and steep rises in inflation, the utilities' expenditures for power plant construction have risen sharply over the last decade, exacerbating the capital-intensive nature of the industry. Though the total capacity growth of approximately 291 gigawatts in new coal-fired and nuclear capacity expected over the next 20 years is only moderate, the high cost of power plant construction will severely strain the industry. 3/ In 1970, electric utilities spent roughly $11 billion (in nominal dollars) for new equipment; by 1980, annual expenditures for new equipment had exceeded $29 billion. This 160 percent increase in annual capital investment, however, augmented total capacity by only 40 percent, and this trend is expected to continue. By the year 2000, expanding electrical capacity is expected to entail capital investments of more than triple the 1980 level (in nominal dollars), though capacity is anticipated to increase by only 44 percent overall.

Air pollution control costs are partially responsible for these escalations. In 1971, coal-fired power plants (equipped only with controls for particulate emissions) cost an average of $210 per kilowatt (in nominal dollars). In 1980, capital costs had risen to approximately $1,100 per kilowatt for a facility using wet scrubbing and to approximately $1,000 per kilowatt for a facility using dry scrubbing (in nominal dollars). (Chapter II describes these processes.) This represents a real cost increase of between 150 to 180 percent. Of this total, air pollution control requirements are responsible for approximately 25 percent, and cost escalations in basic materials and construction account for the remaining 75 percent.

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3. The breakdown of this projected total new capacity is 168 gigawatts of coal-fired generation and 123 gigawatts of nuclear power.

The Congressional Budget Office has estimated that deferring investments that would be made to meet the NSPS of 1978 would save the industry some $19.4 billion between 1980 and the year 2000. This savings would represent only about 6 percent of the estimated $320 billion needed for new coal-fired and nuclear capacity over the period and 11 percent of those expenditures needed solely for new coal-fired capacity ($176 billion). 4/

THE EFFECT OF AIR POLLUTION CONTROL COSTS ON THE ELECTRIC UTILITIES' FINANCIAL POSITION

The aggregate costs of air pollution, though high, appear not to be generally responsible for the utilities' worsening finances or for their difficulties in raising capital. The CBO's analysis of this issue, using bond ratings as a measure of creditworthiness, leads to the conclusion that the market perceives utilities that have invested in pollution control to have much the same financial soundness as the general population of electric utilities.

In an attempt to quantify the effects of pollution control investment on financial integrity, the CBO compared bond ratings of the 100 utilities listed by the investment firm Salomon Brothers against two subgroups (see Table 3). 5/ The first of the subgroups is a sample of 29 utilities that had 15 percent or more (that is, a high proportion) of their construction-work-in-progress accounts dedicated to environmental control equipment in 1979. The other subgroup, representing utilities with significant investment in flue gas desulfurization technology, consists of 21 companies, each with at least one scrubber system in operation.

Both of the subgroups in CBO's analysis--that is, those utilities with substantial financial commitments to pollution control--ranked generally better in terms of bond ratings than did the general population of 100 utilities. In fact, the scrubber group ranked best, with 62 percent of ratings at or above the straight "A" rating (shown in the table as A/A). Next in

4. These data do not reflect costs of transmission and distribution.

5. The Salomon Brothers rating designations represent a compilation of bond ratings set by other investment firms, specifically Moody's and Standard and Poor's; hence the dual appearance of the Salomon Brothers listings. A Salomon Brothers "AAA/Aaa" listing reflects Standard and Poor's AAA bond rating and Moody's Aaa rating.

order was the group with 15 percent of construction-work-in-progress investments devoted to environmental commitments. The general population had the lowest distribution rated above A, with only 38 percent of ratings higher than the straight A rating. In both cases, the deviation of the subgroups' distributions from that of the general population are significant, suggesting that pollution control investments are more readily undertaken by financially sounder utilities. Using a second analytical approach, however, based on a random sample of utilities from the general population of 100 firms, the CBO found no statistical correlation between bond ratings and the ratio of total investment for construction-work-in-progress to the portion devoted specifically to environmental control.

To assess whether environmental control costs had affected the status of bond ratings over time, rather than only measure the ratings as of a specific date, the CBO also conducted a check of bond ratings between 1978 and 1980. In an examination of the same three groups displayed in Table 3, no significant pattern of rating changes emerged. The only group that had no upgradings during that period was the scrubber group, in which three firms with bond ratings below the A level were downgraded by one point or more. This same group, however, also contained some of the highest rated electric utilities.

The above results suggest that factors other than pollution control investment may more strongly influence the utilities' financial health as measured by bond ratings. Regulations enacted by public utility commissions appear to be a strong influence. According to various investigations (including another CBO study 6/), unfavorable regulations--those that prohibit or delay adequate return on capital investment--can be major factors in determining lower bond ratings, leading in turn to higher financing costs. One analysis, for example, reported that 90 percent of the utilities with low bond ratings--between A and BBB as set by Standard and Poor's--are outside of jurisdictions described as having "very favorable" regulatory climates. 7/ At the same time, only 13 percent of those utilities with strong bond ratings, as high as AA or AAA, were found to be within the jurisdictions with PUCs thought to have "unfavorable" regulations, as assessed by five investment firms.

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6. See forthcoming CBO paper on regulatory reform.

7. See Peter Navarro, "Electric Utility Regulation and National Energy Policy," Regulation, American Enterprise Institute Journal on Government and Society (January/February 1981).

TABLE 3. BOND RATING DISTRIBUTION OF 100 RATED ELECTRIC UTILITIES AND SAMPLE SUBGROUPS WITH INVESTMENTS IN ENVIRONMENTAL CONTROL (Percent distribution)

Bond Ratings a/ (Salomon Brothers Compilations)	All 100 Electric Utilities with Bond Ratings	Top 29 Utilities with Minimum of 15 Percent of CWIP b/ Funds Dedicated to Pollution Control	21 Utilities with Scrubbers in Operation
Aaa/AAA	1	None	4.8
Aaa/AA or Aa/AAA	1	3.4	4.8
Aa/AA	26	31	38.1
Aa/A or A/AA	10	10.3	14.3
A/A	32	31	28.6
A/BBB or Baa/A	8	3.4	None
Baa/BBB	19	20.7	9.5
Baa/BBB or Lower	3	None	None

SOURCES: Salomon Brothers, Industry Analysis, "Electric Utility Common Stock Market Data" (March 2, 1981); U.S. Department of Energy, Statistics of Privately Owned Utilities in the United States (October 1980); Environmental Protection Agency, EPA Utility FGD Survey: October-December 1980 (February 1981).

a. Double listings represent a range.

b. Funding for construction work in progress.

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Mitigating Factors--Federal and State Provisions

If the conclusion derived from the foregoing analysis is correct--that investments in pollution control do not adversely affect the financial performance of utility companies--then it is reasonable to ask why not. What factors can mitigate the high costs of efforts to meet emission standards? The CBO has explored two areas in which mitigating factors can be found: federal tax provisions, and certain aspects of federal and state regulations on ratemaking that specifically make allowances for environmental control costs.

Several federal tax programs that apply to the utilities work to ease the burden of pollution control costs. These include accelerated depreciation allowances (also called rapid amortization allowances), an investment tax credit, the availability of industrial development bonds (IDBs) to finance pollution control hardware, 8/ and the routine tax treatment of expenditures for working hardware as tax-deductible business expenses.

Under the accelerated depreciation provisions, which effectively constitute a tax subsidy, a power company with a generating plant that has been in operation since before 1976 may claim depreciated value for any pollution control improvement applied to that plant over a 60-month period, even though the actual useful life of the improvement may be considerably longer. Coupled with this provision, an investment tax credit of 10 percent, granted under the Tax Reform Act of 1978, can be used with the rapid amortization provisions, unless IDBs (discussed in more detail below) are used to finance expenditures, in which case only a 5 percent tax credit can be applied. These special provisions, helping older utilities to finance pollution control efforts, can enhance short-term revenues and offset overall financing costs.

Another avenue offering considerable tax advantages to new utilities investing in pollution control is available through the use of IDBs. Issued for a public purpose either by state or municipal governments or by local industrial development authorities, IDBs for pollution abatement can furnish long-term financing on which the interest to buyers is tax-free. This last feature allows a project financed with an IDB to cost the bond issuer less in interest than if a taxable form of financing were used. When the proceeds from a bond issue go toward a pollution control system, the owning firm pays all principal and interest to the bondholders, often through lease agreements. In effect, no municipal money is involved in such a transaction.

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8. These are sometimes called pollution abatement revenue bonds.

If the municipality does guarantee payment to the bondholders, the IDBs are considered general obligation bonds of the municipality, whereas no such guarantee classifies the bonds as revenue issues that depend upon the funds generated by the benefiting firm.

Utilities appear to have relied more heavily on these IDBs than have any other industries; between 1971 and 1978, some 52 percent of all pollution abatement revenue bond monies went to utilities. The average cost of IDBs for pollution control hardware issued for the benefit of these same utilities was 5.97 percent, while the average cost of long-term debt to utilities for the years 1971 through 1978 was 7.98. Thus, the cost of capital from this form of financing was lowered by 2.01 percentage points.

Altogether, the use of these special tax allowances and IDBs (or other similar revenue bonds) can reduce utilities' pollution control costs significantly. A recent study that examined pollution control costs for electric utilities in a portion of the Ohio River Valley showed that air pollution control expenditures could be reduced by as much as 18 percent through full exploitation of these various allowances. 9/

Other provisions, notably certain federal and state rate-making rules on pollution control investments, can also be credited with a role in easing the burden on utilities of investing in pollution control hardware. Both the Federal Energy Regulatory Commission--which regulates interstate electricity rates--and more than half of all its state counterparts (the public utility commissions, which regulate intrastate rates) allow utilities to collect a return on part of or all investments for environmental construction-work-in-progress. 10/ (This allowance is distinct from the PUCs' typical prohibition against recovery of general construction costs, which utilities cannot incorporate in their rate bases until after the plant begins operation.) The advantage of this allowance is that it yields actual cash earnings for utilities on assets being constructed; it also obviates the crediting against income of a noncash allowance for funds used during construction--an accounting method that can erode earnings and hence stock and credit ratings. In general, the charging of construction-work-in-progress in the rate base can result in lower capital costs to the utility and lower lifetime

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9. See JACA Corporation, "The Economic Impact of Regulating Air Pollution in the Ohio River Valley," draft report prepared for the National Commission on Air Quality (December 1980).

10. See National Association of Regulatory Utility Commissioners, "1979 Annual Report."

electricity costs to the consumer. 11/ (This subject is discussed in greater detail in Appendix C.)

11. This discussion is confined to allowances already in existence before enactment of the Economic Recovery Tax Act of 1981 (P.L. 97-34). The potential benefits of the new law, which includes more liberalized depreciation allowances, on utility finances and cash flow have not been included in this analysis. For a discussion of potential benefits, see Donald W. Kiefer, "The Impact of the Economic Recovery Tax Act of 1981 on the Public Utility Industry," Congressional Research Service (January 15, 1982).

CHAPTER IV. PROMOTING RELIANCE ON COAL AND THE EFFECTS OF THE CLEAN AIR ACT

A major goal of U.S. energy policy to foster the nation's independence from foreign oil suppliers is to promote the burning of coal in electric power generators instead of oil or gas. Although the United States holds a full 31 percent of the world's recoverable reserves of coal, combustion of that fuel furnishes only about one-half of the nation's electricity, with oil and gas providing some 26 percent. (Nuclear and hydroelectric power account for the balance.) Thus, although exploitation of the coal resource has already risen appreciably, opportunities to replace far greater quantities of oil and gas still exist.

Both the Energy Supply and Environmental Coordination Act (ESECA) of 1974 and its successor, the Power Plant and Industrial Fuel Use Act (PIFUA) of 1978, were specifically designed to reduce oil and gas consumption in both new power plants and older facilities already capable of burning coal. Under the latter legislation, the PIFUA, the federal government can order that utilities operating generators that had at one time been converted from coal to oil reconvert those generators back to coal. In addition, utilities are effectively prohibited from burning oil or gas in new major power plants. Thus, a major goal of federal energy policy is also to encourage the accelerated replacement of gas- and oil-fired capacity with coal-burning plants.

Air pollution control policy, articulated by the federal government in the Clean Air Act and by state and local authorities in their own regulations (state implementation plans), can strongly influence the economics underlying the utilities' choices between reconversion of a power plant or its replacement, and continuing to rely on gas or oil. Replacement--involving major capital investment in new plants, which are subject to the act's 1978 NSPS is demonstrably expensive, as indicated by the analysis in the preceding two chapters. Desulfurizing flue gases by means of scrubbers, just one of the cost components entailed in meeting the 1978 NSPS, is an expensive but requisite technique. Reconversion is usually cheaper, since it rarely entails scrubbers. Reconversion has its own significant costs, however, including the possible need to upgrade the boilers and burners to use the particular coal involved, upgrade coal-handling equipment, and modify or replace particulate control devices.

This chapter examines the influence of the Clean Air Act and other factors on the economic choices for utilities between reconversion, replacement, or maintenance of existing oil- or gas-fired capacity. Results of the

Congressional Budget Office's analysis suggest that the costs of reconversion can be substantially less than continuing to burn gas or oil in coal-capable boilers; they also conclude that economic benefits associated with coal use are possible even with full replacement. At the same time, however, they point to oil prices as a strongly influential factor in the cost effectiveness of turning to coal to generate electricity. So long as the growth rate of world oil prices remains depressed, full replacement of oil- and gas-fired capacity may have difficulty proving its economic benefit. 1/

PREVAILING REGULATIONS FOR COAL CONVERSIONS

Distinct from new plants, which are uniformly subject to the federal NSPS of 1978, old plants that are candidates for reconversion can fall subject to a complex mix of federal and state regulations, including exemptions. Two types of reconversion projects are exempt from both NSPS and new source review under the act's "prevention of significant deterioration" program (see Chapter II and Appendix A): power plants ordered to convert to coal under the PIFUA of 1978, and voluntary reconversion of plants that were capable of burning coal before January 1, 1976. Most major utility reconversion candidates fall into these two categories. Both of these types of reconversions must meet the state emissions control requirements for coal-fired power plants of their same vintage, or they must comply with alternate regulations negotiated with the states and approved by the federal government (that is, the EPA). All other reconversions, while generally exempt from the 1978 NSPS, must undergo the PSD new source review process. Few if any reconversion candidates would fall under this latter category.

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1. Since early 1981, a strong downward pressure in world oil prices has occurred in response to excess production. Though residual oil prices have fallen in the spot markets, some by $7 per barrel from their peak price (approximately $34 per barrel), long-term contract prices remain high (approximately $33 per barrel). Analysts anticipate that revived economic growth in the United States and other countries will, by the mid- to late-1980s, spur a resumption of rising rates in world oil prices similar to those observed in the late 1970s. However, how long it will take for oil prices to regain their peak levels (in real terms) is unknown.

COST ANALYSIS--THE POTENTIAL BENEFITS OF RECONVERSION OR REPLACEMENT COMPARED TO CONTINUATION OF OIL OR GAS USE

To quantify and compare the economic effects of Clean Air Act regulations on power plant conversions, the CBO calculated the annual capital and maintenance costs of two possible reconversion cases and one replacement case. The lower-cost reconversion case, requiring no scrubber but using low-sulfur coal, would be completed at a capital cost of $150 per kilowatt. The higher-cost example, requiring a wet scrubber to meet assumed stricter state standards and burning high-sulfur coal, would be completed at a capital cost of $600 per kilowatt. 2/ The replacement example would require a capital cost of $1,160 per kilowatt. (All cases examined here were assumed to meet the applicable environmental standards. The two reconversion examples are assumed to meet all state and local regulations; the one replacement case is assumed to comply with the federal 1978 NSPS.)

The assumptions used in the analysis reflect upper-bound costs for both reconversion and replacement. In all cases, a 10 percent real rate of interest for capital investments was assumed, using a 15-year period for reconversion and a 20-year period for replacement (accounting for the possibly shorter operating life of a reconverted facility). The price of coal in all cases was assumed to rise at a real annual rate of 2.7 percent.

To allow comparison with the costs of using oil, the CBO also computed the operating costs of oil-fired capacity under two different assumptions regarding oil prices. (The maintenance of oil-fired capacity was assumed to entail no capital expenditures.) One assumption used was no real rise in oil prices; the other applied a constant 2 percent real rise over a 20-year period. The result yields not only a general comparison of electricity costs as determined by fuel, but also an illustration of the sensitivity of economic benefits from conversion and replacement to differing behavior of oil prices. This five-part comparison and an explanation of all underlying assumptions are displayed in Table 4.

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2. The range of reconversion costs were obtained from plant-by-plant reconversion estimates prepared by the Edison Electric Institute for use by ICF, Incorporated. See ICF, Incorporated, "A Preliminary Economic Analysis of Reconversion of Coal Capable Utility Boilers," prepared for the Edison Electric Institute (April 25, 1980).

TABLE 4. CAPITAL AND GENERATING COSTS FOR A 500-MEGAWATT OIL-FIRED, RECONVERTED OIL, AND NEW COAL-FIRED POWER PLANT

Case	Capital (In dollars per kilowatt)	In mills per kilowatt-hour: Annual Fixed Capital	Annual Operating	Fuel	Total Generating
A. Low Cost Conversion	150	3.2	7.5	26.6	37.3
B. High Cost Conversion	600	12.9	12.6	19.2	44.7
C. Replacement	1,160	22.2	10.1	19.2	51.5
D. Oil Plant with No Real Fuel Price Increase	None	None	2.0	48.4	50.4
E. Oil Plant with 2 Percent Fuel Price Increase	None	None	2.0	60.0	62.0

With either low- or high-cost plant reconversion, the generating costs of 37.3 and 44.7 mills per kilowatt-hour, respectively, are lower than current oil-plant generating costs of 50.4 mills per kilowatt-hour, even assuming no real rise in oil prices. 3/ In comparison, the replacement case of a new coal-fired power plant equipped with a scrubber (having a generating cost of 51.5 mills per kilowatt-hour) is cost effective only if oil prices rise by 2 percent in real terms over the next 20 years, resulting in an oil-plant generating cost of 62.0 mills per kilowatt-hour. The generating

3. These reflect generating costs only and do not include the costs of transmission and distribution.

TABLE 4. (NOTES ON ANALYTICAL ASSUMPTIONS)

A. No scrubber; low-sulfur coal burnt; average fuel cost over 20 years, starting at $38 per ton delivered price, rising at an annual real rate of 2.7 percent; 10 percent real financing costs for reconversion and particulate emissions control upgrading.

B. Wet scrubber; high-sulfur coal burnt; average fuel cost over 20 years, starting at $33 per ton delivered price, rising at an annual real rate of 2.7 percent; 10 percent real financing costs for reconversion, particulate emissions control upgrading, and scrubber retrofit.

C. New coal-fired plant with wet scrubber, high-sulfur coal burnt; fuel and financing costs same as Case B.

D. No capital outlays; fuel costs constant $31.50 per barrel for 20 years.

E. No capital outlays; average fuel cost over 20 years, starting at $31.50 per barrel, rising at an annual rate of 2 percent.

SOURCE: Congressional Budget Office.

cost of a new coal plant burning low-sulfur fuel also was calculated, assuming a construction cost of $975 per kilowatt. Interestingly enough, the resulting generating cost of 50.3 mills per kilowatt-hour (not shown in Table 4) is quite close to the replacement example of 51.5 mills per kilowatt-hour, which includes a scrubber.

Although full power plant replacement under these assumptions may not be economic unless oil prices begin to rise at some real rate from their 1980 levels of approximately $31.50 per barrel, it does become economic even assuming constant real oil prices if a 6 percent real interest rate, rather than a 10 percent rate, is applied. For analytical purposes, a 10 percent real rate of interest is often used in assessing effects of regulations and was used in these estimates both to allow comparison with other

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analyses and to demonstrate upper-bound costs. In practice, however, real rates of 6 percent or less more accurately represent true interest charges on capital for the electric utilities.

INHIBITING FACTORS

Although the Clean Air Act appears not to be a decisive factor in the economic advantages of reconversion, other factors do impede the rate at which reconversions can occur. These result from a combination of federal and nonfederal regulations.

Economic Constraints at the State Level

Underlying all other factors that may tend to discourage reconversion or replacement of oil- and gas-fired power plants are the financial condition of the individual utility and rate-making regulations imposed by the public utility commissions (see Chapter III). Many of the large oil-consuming utilities are in poorer financial condition than the general utility population and would face difficulty raising the necessary capital. Examination of a list of conversion candidates prepared by the Edison Electric Institute shows that only four (22.3 percent) of the 18 rated utilities on the list have higher than "A" ratings as reported by both Moody's and Standard and Poor's. 4/ In comparison, the general population of 100 rated utilities shown in Table 3 in Chapter III have 38 percent listed at ratings above A.

Compounding these difficulties are PUCs' decisions that discourage reconversion and replacement by delaying a return on investment for construction projects but providing, through fuel adjustment clauses, immediate relief from higher fuel costs (see Chapter III). These factors tend to perpetuate dependence on oil and gas. The net result of such constraints is a systematic bias against capital investment. A utility company that would experience a severe cash-flow problem while pursuing a conversion project may defer any such undertaking indefinitely. Nonetheless, some others, encouraged by the eventual prospect of savings from burning coal (even a high-cost reconversion plant of 500 megawatts can save roughly $1.4 million per month) have tolerated the short-term financial risks and proceeded with conversion plans.

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4. See Salomon Brothers, "Electric Utility Stock Market Data," Industry Analysis (March 2, 1981).

Administrative Impediments in the Clean Air Act

Many of the problems arising from the Clean Air Act can be characterized as administrative. Most reconversion projects fall under individual state emissions regulations, some of which are extremely strict as a result of encouraging oil consumption in place of coal in the 1960s and early 1970s for environmental reasons. Utility companies may seek to relax these state-imposed emissions limits in order to curb reconversion costs, often leading to long periods of negotiation between the utility, the state, and in some cases the EPA, which also has authority to enforce state plans. To arrive at a mutually acceptable emissions standard, the utility firm must submit a detailed description of the effects of the planned reconversion project on ambient air quality, including what measures will be taken to control emissions. The submission and review process is time-consuming and requires considerable technical expertise. Overall, both voluntary conversions and those mandated by federal regulations can involve two years or more of administrative effort before the start of conversion activities.

Because of inflation and deferral of cheaper energy-producing capacity, a utility planning conversion of a 500-megawatt generator costing $600 per kilowatt can lose $3.4 million a month (in nominal dollars) to such administrative delays. This may be compared to the monthly savings of $1.4 million (in nominal dollars) obtainable by that same conversion. Thus, though conversion to coal remains economically advantageous, some streamlining of the administrative requirements to speed implementation of conversion plans would enhance that advantage.

Technical Problems During Work in Progress

Once construction begins on a conversion project, technical problems can slow its progress. Late delivery of equipment and labor shortages can cost a firm some $3.5 million a month (in nominal dollars), assuming 30 percent completion of the project at the start of delay (again, assuming a 500-megawatt plant reconverted at $600 per kilowatt). The prospects of such delay once funds have been committed--postponing the anticipated savings of $1.4 million a month--can be particularly discouraging to firms in light of PUC regulations that generally prohibit recovery of capital investments for projects under construction.

THE IMMEDIATE PROSPECTS FOR CONVERSION

Despite these hindrances, many conversion projects are under way or planned. In a review of 14 utilities, the General Accounting Office reported that six firms were planning 25 reconversions, and two other companies had notified the Department of Energy that they plan to reconvert five additional units. 5/ Conversion of all 30 units would displace the use of some 190,000 barrels of oil per day. Potential for even greater oil displacement is projected by the Department of Energy, which estimates that as many as 520,000 fewer barrels per day of oil or gas equivalent might be consumed through conversions. 6/

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5. See General Accounting Office, "Financial and Regulatory Aspects of Converting Oil-Fired Units to Coal," report to the Chairman, Senate Committee on Energy and Natural Resources (November 21, 1980).

6. See Department of Energy, "Fuels Conversion Program Power Plant Profiles" (January 1981).

CHAPTER V. THE U.S. COAL MARKET AND THE CLEAN AIR ACT

To whatever extent the Clean Air Act influences the utility industry's use of coal, it may also indirectly affect the U.S. coal market. The analysis in this chapter assesses that indirect but important relationship, both as it appears to have operated thus far and as it may in the near future. As the facet of the Clean Air Act most influential to utilities, and in turn to the coal industry, the evolving new source performance standards (see Chapter II) governing gaseous and particulate pollutant emissions are a focal point of this analysis.

As background for evaluating the act's effects on coal markets, this chapter gives an overview of the nature of the coal resource and the factors that influence its purchase by electric utilities. The chapter then reviews the effects seen to date of the first NSPS of 1971. It then projects how the more rigid NSPS of 1978 are likely to influence the supply and distribution of coal through the year 2000.

THE NATURE OF THE U.S. COAL MARKET

The electric utility industry is the nation's largest user of coal, today accounting for some four-fifths of all domestic consumption. Roughly half of all U.S. electricity is now derived from coal. In 1979, some 550 million tons of coal went to utilities; by the end of this century, if current emissions standards remain in force, that figure should more than double, reaching an annual total of 1.2 billion tons. 1/ To meet this demand, coal production in nearly all regions is expected to rise. The actual distribution of this increase will probably not be uniform, however, and the Clean Air Act will have a role in altering the patterns of growth.

Despite the fairly uniform regional distribution of the nation's coal deposits--all but a few major geographic areas have at least some coal

1. While the use of coal by electric utilities has been rising, demand in other sectors of the economy has been falling. Between 1970 and 1979, coal use by electric utilities rose some 65 percent but fell in all other industries, including steel making, by a combined 30 percent. Residential and commercial users account for only 1 percent of all coal purchases.

deposits--the market value of coal varies between and within regions. Two main characteristics affect the value of the delivered price of all coal:

- o How it is mined--whether by deep-mining, which is typically the costlier method, or by surface techniques; and

- o What distances it must travel from where it is produced to where it is used.

A third factor--sulfur content--is also influential, though of lesser importance, inasmuch as the demand for low-sulfur coal may be enhanced by emissions limits on sulfur dioxide. Energy content, another fuel-related value, has less influence on the price of coal at the mine than on the delivered price, since more volume of a low-energy-content coal must be shipped than of a high-energy-content coal. Aside from these factors, which can influence delivered price, the fuel value of different coals is essentially unvaried, since most new power plants can be designed to handle any particular coal chosen for long-term consumption.

Regional Characteristics of Coal

In general, U.S. coal production can be divided into three regions: the area east of the Ohio and Mississippi rivers (particularly the Appalachian region); the Midwest (from the Mississippi to the western borders of Minnesota, Nebraska, Kansas, Oklahoma, and Texas); and the West. (See Figure 3.) Within all three regions, both deep- and surface-mining methods are used, though to different extents. In the East, the choice of mining method is roughly equally split between surface- (40 percent) and deep-mining (60 percent). In the Midwest and the West, however, far more surface- than deep-mining is done (see Figure 4). Because surface-mining is typically more productive, coal recovered by this method usually has a sizable cost advantage over coal from deep mines. 2/

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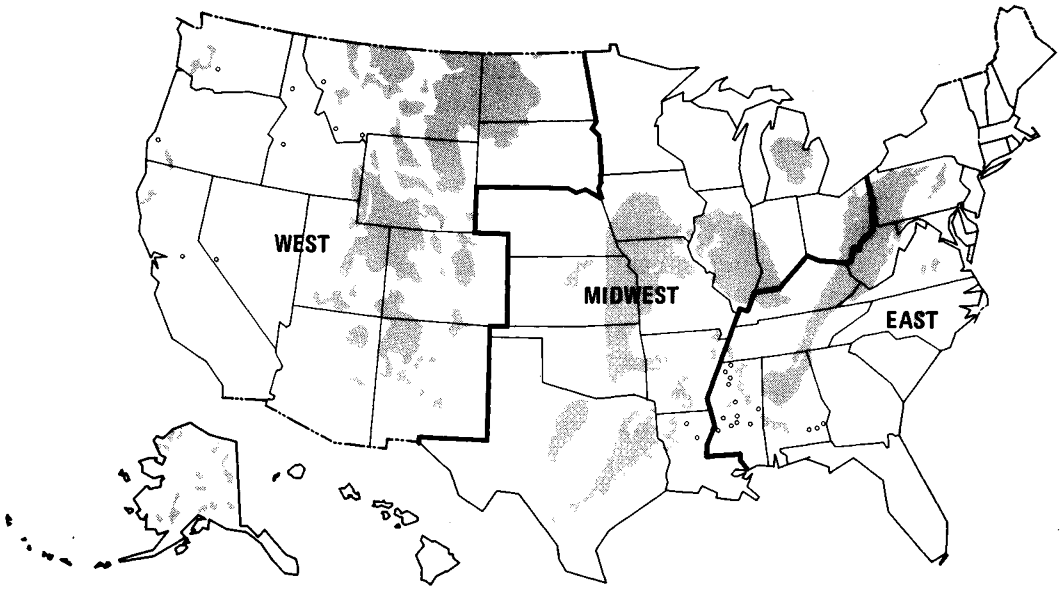
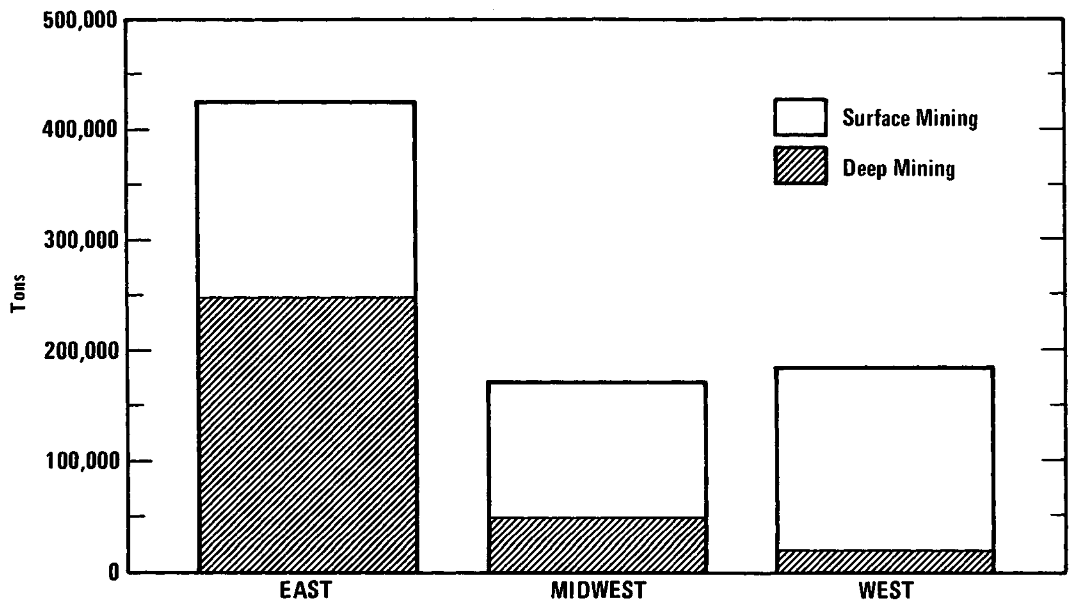
2. The location of the coal resource generally determines the recovery method used. Much Appalachian coal is buried in seams deep within mountains or hills; deep-mining is the only method available to recover much of this coal. For more superficial coal, large machines can remove the overlying soil (overburden), exposing the coal. This method, also called strip mining, tends to be more productive. In addition, because of the terrain involved and depth of overburden, many western surface mines are more productive than eastern surface mines, though other factors, such as the age of the mines, also can influence productivity.

Figure 3.
U.S. Coal Fields and Producing Regions



SOURCE: Adapted by CBO from The President's Commission on Coal, "Coal Data Book" (February, 1980).

Figure 4.
Total U.S. Coal Production by Region and Mining Methods: 1979



SOURCE: Adapted by CBO from U.S. Department of Energy, *Coal Production—1979* (April 30, 1981).

The regional pattern of coal's sulfur content also varies from region to region, and within particular regions. The East contains coals with sulfur contents ranging from below 1 percent to above 3 percent by weight. The Midwest offers little low-sulfur coal; most coal in that region is characterized by moderate- or high-sulfur contents, generally above 3 percent. The West has sizable reserves of low-sulfur coal; more than three-fourths of all western coal has a sulfur content below 1 percent. In contrast, the energy content of eastern and midwestern coal reserves is generally higher than in the West.

Coal production in the United States has been shifting slowly westward. In 1960, the producing states of the East accounted for 95 percent of total U.S. production. By 1970, the East's share of the market had declined to 85 percent and by 1979, to approximately 75 percent. 3/ The reasons for this trend are the high productivity of western surface mines, the growth in western energy consumption, and to some extent, the increased nationwide demand for low-sulfur coal to meet both state and federal environmental regulations. In the future, the revised federal emissions standards--the NSPS of 1978, with their implicit requirement of scrubbers on all new utility generators--may somewhat slow this westward trend in coal production, inasmuch as the current regulations provide little if any economic advantage to users of low-sulfur coal that is not locally produced.

Factors That Influence Choices of Coal Supply and Delivered Price

Although coal is produced in all three regions of the country, much coal, particularly western coal, is shipped to other geographic regions. Although under ideal conditions utilities would elect to burn local coal only, several factors often combine to influence them to do otherwise. Local mining costs, sulfur content, and the availability of a secure long-term supply often prompt utilities to buy coal produced in other areas, so long as they obtain the lowest delivered price for the fuel desired. The chief factor affecting utilities' coal purchasing decisions is the fuel's so-called free-on-board (FOB) price. The FOB price, coal's counterpart to oil's wellhead price, is its cost at the place of production, including mining and processing costs and producers' profit, but no transport cost.

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3. See Martin B. Zimmerman, The U.S. Coal Industry: The Economics of Policy Choice, the MIT Press (1981). The 1979 figure is based on the CBO analysis.

Mining method is the most significant factor affecting FOB costs. In general, surface mines are from two to three times more productive than underground mines, and coal from surface mines often sells for about one-half the price of coal from deep mines. In 1979, the average FOB value per ton of deep-mined coal was $32.76, while that of surface-mined coal was $17.58. 4/ To determine the delivered price of a particular coal, however, transporta-tion rates and distances hauled must be added to FOB costs.

Most coal moves by train. Rail haulage rates generally range from 10 to 30 mills per ton for each mile transported (termed a "ton-mile"). Higher rail rates predominate in the East, although in several western areas, rail rates have risen steeply over the last few years. At a cost of 15 mills per ton-mile, a haul of 300 miles can increase the FOB coal price by $4.50 per ton. For 1,000-mile hauls, $10 to $20 can be added to the price of each ton of coal. Though unusual in the East, where coal hauls average 300 miles, 1,000-mile hauls are not uncommon in the West.

Within a region, coal's delivered price is largely a function of the region's predominant mining method, since the value of local coal establishes the upper value for coal shipped from other areas. Delivered coal prices are highest in the East--where approximately half the coal is mined underground--ranging from $37 to $44 per ton. Delivered coal prices in the midwest are lower, ranging from $18 to $33 per ton, corresponding to the greater use of surface-mining methods in this area. Prices for coal delivered to western users, where surface-mining also predominates, are lowest, ranging from $14 to $18 per ton. 5/

Low mining costs, together with regulations encouraging the use of low-sulfur coal (such as stricter state standards on some older power plants and the 1971 NSPS on newer units) encourage the shipment of much western coal eastward. Most coal from western deposits happens to be low in sulfur content and because it is mostly surface-mined, tends to have lower FOB prices than eastern, deep-mined low-sulfur coal. As a result, western surface-mined low-sulfur coal is an attractive alternative to some buyers in the East and the Midwest in particular.

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4. See U.S. Department of Energy, "Energy Data Report," Coal Production-1979 (April 30, 1981).

5. See U.S. Department of Energy, Cost and Quality of Fuels for Electric Utility Plants--December 1980, Monthly Report (April 7, 1981).

Several factors limit the demand for western coal in the East and Midwest, however. For one, the East (notably Appalachia) holds large quantities of low-sulfur coals. Although much of this supply is mined (by either method) at a higher cost than western surface-mined coal, it is closer to many eastern purchasers and transportation costs thus can be lower. For eastern users, the costs of shipping western coal can often raise its delivered price above that for comparable low-sulfur eastern coal. Another major factor is the status of many sulfur dioxide regulations for old power plants. In many areas of the Midwest, the absence of strict sulfur dioxide regulations for many older power plants, allowing them to use indigenous surface-mined higher-sulfur coal, obviates the need to purchase low-sulfur coal from another region. Finally, through the imposition of a strict scrubbing requirement on all coal used in new power plants, the current NSPS provide little stimulus for increasing the import of low-sulfur coal.

THE 1971 NEW SOURCE PERFORMANCE STANDARDS AND U.S. COAL CONSUMPTION

Concerns about distortions in U.S. coal markets shaped the Congress' revisions in 1977 of the Clean Air Act's new source performance standards. Under the old NSPS of 1971, utility companies could--and did--rely heavily on low-sulfur coal to meet mandatory mass pollutant emissions limits. (As stated in Chapter II, the maximum allowable amount of sulfur dioxide gas emitted from a steam boiler's stack was 1.2 pounds for every one million BTUs of fuel burnt.) Required only to meet this mass emissions limit by whatever method was economical, many utility managers elected to burn low-sulfur coal rather than install costly and still optional scrubbers; scrubbers were chosen rarely, usually in instances in which low-sulfur coal was not available within a reasonable distance.

From this apparent preference for low-sulfur coal under regulations promulgated in response to the Clean Air Act, the Congress concluded that two related distortions in need of correction existed: that demand for low-sulfur coal was gaining an edge over higher-sulfur coal; and that, accordingly, western coal could flood the market, displacing demand for eastern and more importantly, midwestern coal.

Data on the trend in demands for high- and low-sulfur coal tend to bear out these suppositions, but only partly (see Figure 5). The relative demand for low-sulfur coal did indeed grow during the late 1970s, coincident with the utilities' implementation of plans to meet the mass emissions limits